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EDISON

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July 22, 2005

California Energy Commission
Docket Office
Attn: Docket No. 04-IEP-1D
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Re: Southern California Edison's written comments to California Energy Commission's "Investor-Owned Utility Resource Plan Summary Assessment" Report

Dear Commission:

Southern California Edison (SCE) submits the following comments on the CEC Staff report titled "Investor-Owned Utility Resource Plan Summary Assessment" 2005 IEPR Committee discussed on June 29, 2005. In addition, per Commission Geesman's request, please also find attached a document describing how SCE implements the "least cost-best fit" principle in its resource evaluation process. The document was originally prepared for and filed at the California Public Utility Commission in June 2004.

If you have any questions regarding these documents, please call me at (916) 441-2369.

Sincerely,

Manuel Alvarez

Enclosure

cc: Kevin Kennedy
Al Alvarado

35003

SOUTHERN CALIFORNIA EDISON COMPANY'S WRITEN COMMENTS ON THE CEC'S "INVESTOR-OWNED UTILITY RESOURCE PLAN SUMMARY ASSESSMENT" REPORT

Docket No. 04-IEP-1D

On June 17, 2005, the staff of the California Energy Commission ("CEC") published a report entitled "Investor-Owned Utility Resource Plan Summary Assessment" ("Report"). This paper summarizes Southern California Edison ("SCE") Company's general comments as presented at the CEC workshop on June 29, 2005 and contains additional detailed comments on the Report.

GENERAL COMMENTS

SCE thanks the Staff for its attempt to summarize the IOUs' filing in its Report. SCE provided data and responses to each and every topic in the CEC's original request. SCE's total filing consisted of more than 3,000 pages and was accompanied by more than 23 MB of supporting data and documentation. Additionally, SCE spent considerable time providing supplemental information and clarification regarding its information to CEC staff members. SCE did this in order to provide the staff with complete and accurate information and analysis.

As part of its submissions, SCE submitted four scenarios as the CEC requested:

- "Reference case" with the Devers-Palo Verde No. 2-500 KV transmission line;
- "Reference case" without the Devers-Palo Verde No. 2-500 KV transmission line;
- An "alternate scenario"; and
- An "accelerated renewables scenario";

It should be noted that none of these scenarios represented SCE's preferred plan. SCE also provided the CEC with assessments and detailed discussions of assumptions used in its filings with regard to:

- Generation cost estimates of the submitted scenarios;
- Local reliability area assessment;
- How a greenhouse gas ("GHG") adder would affect future procurement choices;
- Natural gas and wholesale electricity prices;
- Impact of early retirement of San Onofre Nuclear Generating Station;
- Returning Mohave Generating Station to service as early as 2010; and
- A scenario evaluation of Core/Non core—Departing Load assuming 75% of customers with peak demand of 500 kW or more will depart during 2009-2012.

The Report generally adequately summarizes SCE's submittals. However, the Report does not properly represent SCE's position with regard to some important policy issues and contains factual errors that must be corrected. Since the Report is slated to become a part of the CEC's final recommendation to the California Public Utilities Commission ("CPUC") with regard to the 2006 Long-Term Procurement Proceeding, SCE believes that it is important that the final version of the Report correctly characterize the information provided and fully reflect the concerns of the entities involved in the IEPR process. To assist the CEC in this objective, SCE provides general comments herein on the following three areas:

- The CEC's renewables recommendations;
- The CEC's conclusions regarding Devers Palo Verde 2 ("DPV 2"); and
- The Energy Efficiency ("EE") and Demand Response ("DR") goals of the CEC's reference case.

SCE comments on additional subjects in its “Detailed comments” section below.

The CEC’s Renewables Recommendations

First, as drafted, the Report omits SCE’s concerns about the CEC’s recommendations to increase renewable portfolio standard (“RPS”) requirements. T CEC’s instructions to SCE requested scenarios that exceed the legislatively mandated renewable portfolio standard target of 20 percent. The instructions did this, despite the CEC’s failure to perform any rigorous assessment of the feasibility of procurement targets above the 20 percent requirements. Instead, the CEC relied , principally, on its assessment of the gross renewable resource potential. Such an assessment, however, did not apply any economic filter filters to determine what resources can be expected to be developed and at what installation and operational costs (including transmission costs).

Second, the CEC requested that SCE develop an “Accelerated Renewables Scenario” assuming a 31% level is reached by 2016, while other LSEs were instructed to use a lower target of 28%. The CEC has yet to offer any rational basis for requiring greater renewable procurement targets for SCE, stating only that SCE is already the nation’s leader in renewable procurement. Such reasoning for the imposition of an additional burden on SCE is illogical, unsubstantiated by any meaningful analysis, and unsound. California has gone to great lengths to ensure that resource adequacy requirements are borne equally by all load serving entities. The same policy should also apply with respect to all procurement obligations in order to ensure that the burden of achieving desired policy objectives is distributed equally and equitably among all who are to receive the benefits of these policies.

In addition to these general statements, SCE includes more specific comments on “Chapter 4: Renewable Portfolio Standard and the Accelerated Renewables Scenario” in the “Detailed Comments” section of this submission.

The CEC's Conclusions Regarding DPV 2

The Report's Transmission analysis misinterprets the information SCE provided regarding DPV 2, despite SCE's attempts to ensure clarity on this subject. SCE's submittals in the IEPR process attempted to show that DPV 2 needs to be evaluated on a California Independent System Operator's ("CAISO") basis as it is a project that will be utilized and paid by all CAISO-jurisdictional LSEs to meet their respective customer needs. The most comprehensive and useful information regarding DPV2 can be obtained from SCE's Certificate of Public Convenience and Necessity ("CPCN") application, filed at the CPUC and the CAISO's analysis.

Instead the staff report looks only at SCE's increases in short-term and spot market purchases and reaches the erroneous conclusion that DPV 2 is being utilized only 13 percent. This conclusion is erroneous in two ways. First, the values being used are "short-term and spot market purchases," not imports as the report asserts. These purchases are from the SP15 market, from which the energy may originate within SP15 or from anywhere outside SP15. Second, the DPV 2 project will provide access to greater generation for all load serving entities within CAISO and not just SCE's customers. The actual usage factor of the DPV 2 project cannot be determined based on the data provided in the Electricity Supply Forms.

The EE and DR goals of the CEC's Reference Case

The CEC requested that SCE prepare "Reference Case" resource plans assuming EE and DR goals approved in the EE OIR and Advanced Metering OIR.[1] However, no credible analysis has been provided by the Joint Staff demonstrating that levels of energy efficiency and demand response beyond SCE's Maximum Reliably Achievable Potential ("MRAP") levels can be cost-effectively and reliably achieved.

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[1] These goals are (1) Price sensitive demand response goals established in D.03-06-032; and (2) Energy efficiency targets for peak demand and energy as adopted in D.04-09-060.

In its IEPR submittals, SCE expressed concern that the required goals are not reliably achievable and submitted an alternative resource plan with EE forecast is based on SCE's Long-Term Procurement Plan. SCE's DR forecast is based on SCE's 2005 program proposal reflecting revisions to SCE's MRAP DR portfolio ordered in D.05-01-056.

Accordingly, SCE reiterates that the basis of future recommendations should be the levels of energy efficiency and demand response identified as reliably achievable and economic. SCE's forecasts meet these criteria while the required goals do not.

In addition to these general statements, SCE also includes more specific comments on "Chapter 2: Energy Efficiency Resources" and "Chapter 3: Price Sensitive Demand Response Programs" sections of the Report in the "Detailed comments" section, below.

DETAILED COMMENTS

Chapter 2: Energy Efficiency Resources

The Energy Efficiency ("EE") section of the Report adequately summarizes SCE's filings related to EE. As the CEC is aware, SCE has already provided preliminary comments on EE to CEC staff members. Most of these comments were incorporated in the Errata For Investor-Owned Utility Resource Plan Summary Assessment ("Errata") issued on June 24, 2005. Still, the Report contains several statements which require modification or additional explanation in order to fully reflect SCE's position. SCE addresses each of these below.

First, at page 30, the Report states, "SCE's assumption that it will be possible to add 970 new GWh in the first year of a new program cycle seems implausible."

This conclusion is baseless. SCE successfully achieved a similar ramp-up between its 2003 program year and its current 2004-2005 program years. SCE has also exceeded its 2004 goals and expects to exceed its 2005 goals. Further, on June 1, 2005, SCE filed Application 05-06-015 requesting funding for a portfolio of programs which are targeted at exceeding the 970 new GWh referenced in this forecast. Far from implausible, SCE’s assumptions are plausible and achievable and SCE is actively moving to meet such goals.

Second, at page 30, the Report states, "SCE's assumption that public goods charge funding will not be available after 2011 also seems unlikely."

As specified in Public Utilities Code §399.8, PGC funding of energy efficiency ends on January 1, 2012. At this time, neither SCE nor the CEC has any basis for assuming that §399.8 will be modified. Consequently, SCE must assume that PGC funding will terminate at the end of calendar year 2011. From a reporting perspective, for this filing, SCE has merely transferred PGC funded program activities into the "uncommitted" or unfunded category in accordance with CEC's definitions of committed and uncommitted.

Third, at page 30, the Commission states, "Since both SCE’s projections and the adopted goals relied on the same potential data, it is unclear why this difference of opinion about what is achievable is so large."

To clarify, SCE does not contend that a Maximum Achievable Potential does not exist. Maximum Achievable Potential is defined as the amount of economic potential that could be achieved over time under the most aggressive program scenario possible. Instead, SCE does not believe that Maximum Achievable Potential accurately characterizes real world considerations. It must be understood that forecasts of Maximum Achievable Potential are based on the assumptions that everything goes right and that all of the potential in the marketplace is successfully converted to energy efficient products and services based on mathematical equations and algorithms without the incorporation of any judgment. However, SCE does not believe it is prudent to base a resource plan on such an approach. Accordingly, SCE submitted a forecast of energy efficiency that is based on a level of energy efficiency that can more reliably be achieved. SCE’s forecast of Maximum Reliably Achievable Potential (“MRAP”) tempers the estimate of Maximum Achievable Potential derived from Kema-Xenergy’s theoretical model with the management judgment of SCE's program planning organizations. MRAP incorporates the realism that is needed to practically use energy efficiency as a resource.

Fourth, at page 36 the Report states, "The CPUC consultants found too little information in the preliminary information to judge either the cost-effectiveness or the reasonableness of the savings associated with proposed program measures."

The CEC's assertion demonstrates a flaw in the CEC's process, not in SCE's submissions. As requested, SCE filed all historical and projected program administrative and incentive costs. Such costs can be found in SCE's submitted Forms 3.1a. Since that information is precisely what the CEC requested, and SCE received no further request for different or additional information, it is not clear why the CPUC's consultants were unable to judge cost effectiveness.

Chapter 3: Price Sensitive Demand Response Program

SCE generally agrees with the Report's conclusions with respect to demand response ("DR"). However, SCE strongly believes there are a number of critical policy issues regarding demand response that were not addressed by the Report. Most of these issues remain to be addressed in R.02-06-001. The text that follows reiterates SCE's positions in A. 05-06-008, *Testimony in Support of Southern California Edison Company's Application for Approval of Demand Response Programs, Goals, and Budgets for 2006 -2008*, June 1, 2005.

For example, the Report fails to address the impact of the fundamental disconnect between the CPUC's definition of its quantitative goals for demand response and the ability of current portfolios of price responsive programs to meet such goals during the 2006-2008 program cycle.

By way of background, in D.03-06-032, the CPUC set aggressive goals for demand response that the utilities were expected to meet through price-responsive programs, beyond demand response achievable through reliability based programs. These demand response goals were set at four percent of total system peak load in 2006 and five percent of total system peak load in 2007 and 2008. At the time those goals were adopted, the term "price- responsive demand response" had not been clearly defined. The targets set in D.03-06-032 were adjusted for 2004 based on the program performance.[2] The original 2005 goal of three percent of total system peak load was later defined based on long term procurement plans.[3] In D.05-01-056, the CPUC decided not to adjust the goals for 2005, and provided needed guidance on how to count demand reductions towards price responsive demand response goals.[4]

While SCE supports developing a strong, diverse portfolio of demand response resources capable of meeting aggressive targets and achieving significant peak reductions, the disconnect described above will make it difficult for the current portfolio of price responsive programs to meet these goals during the 2006-2008 program cycle. This disconnect exists for two main reasons: (1) the interrelationship between price responsive demand response and reliability programs, and (2) the limited breadth of customers who can participate in price responsive programs today. Accordingly, SCE recommends that demand response goals be determined on a portfolio approach and that price response goals be based on the number of eligible participants.

1. Demand response goals should be determined based on a portfolio approach

SCE has a long history of successfully designing and implementing reliability-based demand response programs, including almost 1,300 MW currently enrolled in its interruptible and load control programs. When called upon short notice, these programs deliver reliable demand reductions and help avoid system emergencies.

Given the strong enrollment of SCE's customers in these programs, it is that much more difficult to achieve their substantial participation in the day-ahead programs

2 Administrative Law Judge's Ruling, June 2, 2004.

3 D.04-12-048.

4 D.05-01-056, issued January 27, 2005, p. 8 (defining "price responsive" demand response to programs called on a day-ahead basis, and "reliability" demand response to programs called on a day-of basis).

because any increase in enrollment in price response programs may come at the expense of reliability programs. Said differently, a customer can only curtail its load once on any given day: if the load is committed to be dropped as part of a day-ahead program, that load will not be available as part of a reliability day-of program the next day during an emergency condition. Accordingly, SCE should strive to achieve a diverse array of demand response programs among different customer sectors that include both strong price response *and* strong reliability programs so that these programs do not dilute the load reduction resource available to address both critical peak pricing and emergency conditions. Given the need to have a portfolio of both kinds of demand response programs, it is important that the ultimate demand response goals required of SCE reflect the achievements of both types of demand response programs, and that SCE then seek to achieve a proper balance of enrolling all types of demand response resources.[5]

2. Price response goals should be determined based on eligible participants

Current demand response goals are based on total system peak demand, which includes residential, small commercial, direct access, and large customer load.

Although there are some reliability programs, such as the air conditioner cycling program, that are aimed at smaller customers, the vast majority of approved demand response programs today focus on only the largest customer segment. Because today (and during the 2006-2008 period), only these large customers have advanced metering capable of facilitating their participation in price responsive programs, it is unrealistic to expect that this one customer segment can deliver the entire demand response to meet a goal based on total system peak, especially when, as noted above, these same customers already heavily contribute to reliability demand response resources.[6]By setting reasonable

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[5] If the demand response goal continues to be defined solely as "price response," it is likely that day-ahead programs will eventually "cannibalize" the potential load reductions from day-of programs, leaving less reliability-based demand response resources available during an emergency.

[6] SCE's price response goal of five percent of total system peak in 2007 load equates to nearly 1,100 MW for SCE. Because only the largest customers, representing about 5,500 MW of coincident peak

goals for price response, it is important that the CPUC apply its price response targets based on the potential of *eligible* customers, not *all* customers. A goal of five percent of peak load may be reasonable if it is limited to peak load of customers who are eligible to participate in price-responsive programs. Until cost-effective advanced metering is deployed to more customer segments, price responsive demand response targets should be calculated based on *eligible* peak load, not total system peak. The CPUC is currently investigating the cost effectiveness of advanced metering, but it is clear that significant deployment of advanced metering will not be available to the majority of SCE's smaller customer segments during this 2006 – 2008 application period.

To account for the reality that the "price-responsive" targets should only apply to eligible customers, SCE recommends that any specific goals for price-responsive demand response be based only on peak load of customers with interval metering.[7] For example, the four percent goal for price responsive demand reduction in 2006 should only apply to the load of customers with the proper metering. Assuming that their total eligible peak load is 5,500 MW, a four percent target for price responsive demand reduction in 2006 would be 220 MW, which is within striking distance of the 2004 enrolled price responsive load for SCE of 205 MW.

The paramount goal in the 2006-2008 timeframe should be to achieve actual peak load reduction by any reasonable, cost-effective means possible. Reliability programs such as air conditioning cycling or incentive-based programs such as 20/20 are the only means available to encourage customers that do not have interval metering to reduce peak load in the interim. It is important that demand response targets accurately reflect this reality.

Once demand reduction targets are properly set, the Commission can encourage utilities to exceed them with earnings rewards. The California Energy Action Plan

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demand, are already equipped with advanced metering, these large customers are really the only customers eligible to participate in price response programs in the near future. As it stands today, the target essentially translates to a 20 percent peak load reduction by all of SCE's large customers, which is simply an unrealistic goal.

[7] Roughly three-quarters of SCE's total system peak load is comprised of customers without interval meters.

(“EAP”) adopted by the CPUC, the CEC and the California Power and Conservation Financing Authority (“CPA”) in Spring 2003 explicitly called for the use of utility incentives to increase energy conservation and resource efficiency measures, stating the need to “[p]rovide utilities with demand response and energy efficiency investment rewards comparable to the return on investment in new power and transmission projects.”[8] Legislators also recognized that the proper use of incentives is appropriate to accomplish important policies for demand-side management and included incentives in SB888 and AB57. The concept of earnings rewards has merit, but only if the utilities' performance can be reasonably measured against realistic and appropriate targets.

Chapter 4: Renewable Portfolio Standard and the Accelerated Renewables Scenario

This section is the most problematic part of the Report. It is especially problematic because statements made in certain sections are inconsistent with those made in other parts of the Report. Moreover, the section seems to disregard relevant information provided by SCE and omits or minimizes serious policy issues raised by SCE.

For example, the Report disregards SCE's policy concerns when it fails to address SCE's concerns about the CEC's recommendation that SCE be forced to meet a higher renewables requirement than any other entity in the State. This is evident at page 50 of the Report, under the Heading “Issues Raised by SCE's Renewables Assumptions and Comments,” where the Report states:

> SCE raised serious concerns about renewable goals beyond 20 percent in 2010 and requested the Energy Commission to “undertake a detailed analysis, with meaningful stakeholder input” that considers the following areas of potential impact:
>
> • Deliverability: the transmission additions or upgrades needed to deliver renewable power to end users,

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[8] Roughly a total of 750 service accounts are enrolled in Demand Bidding, CPP tariffs and the CPA Demand Reserves Partnership.

> particularly if RPS obligations are enforced on a statewide level.
>
> • Dispatchability: the electrical system reliability consequences of intermittent and non-dispatchable procurement obligations.
>
> • LTPP requirements: the CPUC-directed requirements of the 2006 long-term procurement plans.
>
> • Rate Impacts: the effect of the above-market RPS costs on rates and whether a public goods charge fund is necessary to fund them.
>
> • IOU Progress: the results of IOUs' ongoing CPUC-directed RPS bid solicitations,
>
> • Other LSE and Publicly-owned utilities (POU) progress: the efforts and results of all other LSEs to achieve 20 percent renewables by 2010.
>
> SCE's transmission submittal also notes the challenges that development of renewable energy poses for transmission development and operation.

The Report's full treatment of this subject is nothing more than a partial reiteration of SCE's previous complaints. The Report contains none of the requested assessment, or even an opinion on the need for such an assessment. Accordingly, it unjustifiably minimizes SCE's concerns about proposed renewable goals set above 20 percent. With the current lack of understanding regarding the potential impact of such an increase, the CEC's recommendation to significantly increase LSEs' obligations to procure non-dispatchable renewable resources or to establish different procurement obligations for different LSEs in the State would be poor public policy.

In the 2004 Energy Report Update, the CEC recommended that a specific target be set for SCE, which is already close to the 20 percent goal, noting:

> In fact, depending on the results of [the 2003 RPS solicitation], SCE may be able to maintain its 20 percent goal without having to issue any RPS solicitations for several years.

> The CEC believes that setting a new and higher target just for SCE will help accelerate renewable energy development statewide . . . . The Energy Commission further believes that SCE's continued leadership will be vital to achieving the State's long-term objectives to commercialize its renewable resources and to promote fuel diversity in the electricity sector.
>
> To minimize the uncertainty regarding SCE's participation in accelerating California's RPS, the Energy Commission recommends state legislation to allow the CPUC to require SCE to purchase at least one percent of additional renewable energy per year between 2006 and 2020.[9]

SCE summarized its objections to this recommendation by stating:

> The CEC has yet to offer any rational basis for this disparate treatment, stating only that SCE is already the nation's leader in renewable procurement. This position is illogical, unsubstantiated by any meaningful analysis, and it is unsound public policy for the reasons discussed below. [10]
>
> To date, despite repeated requests by SCE and other stakeholders, the CEC has declined to perform any rigorous assessment of the feasibility of accelerated or differential procurement targets, relying instead, principally, on its assessment of the gross renewable resource potential. Although this assessment asserts that most in-state renewable resource potential is located in SCE's service territory, the CEC has yet to explain why these resources cannot be developed by other LSEs, nor has the CEC applied any economic filters to determine what resources can be expected to be developed and what are the installation and operational costs of these new projects (including transmission costs).[11]

SCE stated that analysis and public dialogue on these topics should occur "before giving any serious consideration to whether the renewable portfolio standard should be altered to

[9] California Energy Commission, 2004 Integrated Energy Policy Report Update, November 2004, p. 39.

[10] Roughly a total of 750 service accounts are enrolled in Demand Bidding, CPP tariffs and the CPA Demand Reserves Partnership.

[11] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, page 11.

[11]

require increased targets" beyond 20 percent by 2010, noting that "SCE is troubled by the unwarranted differentiation among LSEs." On this topic, SCE elaborated as follows:

> California has gone to great lengths to ensure that resource adequacy requirements are borne equally statewide. The same policy should apply with respect to all procurement obligations in order to ensure that the burden of achieving desired policy objectives is distributed equally and equitably among all who are to receive the perceived benefits associated with those policies.[12]

SCE specifically requests that the CEC revise the Report to reflect an assessment of the need for such a requirement.

Additionally, the Report is inconsistent in several areas under this heading. For example, on page 49, the Report states:

> A detailed review of the QF contracts throughout the study period indicated changes to the level of production of some of the contracts, but did not reveal which contracts would not remain with SCE throughout the study period. There was no discussion by SCE of how it determined which contracts to change the production levels.

Nevertheless, on page 70, the Report states:

> It its Alternate Case, SCE assumed a 10 percent QF attrition rate, meaning that 90 percent of the capacity currently associated with contracts terminating during the planning period will remain under contract with SCE from the date of contract expiration at least through the end of the planning period.

Similarly, on page 71 the Report continues:

> As SCE points out, there can be considerable uncertainty about whether an IOU will continue to procure power from existing QF units after their contracts begin to expire. When contracts expire, SCE points out that owners may choose to terminate their projects for their own reasons. Or

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[12] Comments of Southern California Edison Company to the Scenarios Filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005, pages 10 – 11.

> they may choose to sell their power to other utilities or energy service providers. On the other hand, SCE points out that its 90 percent persistence assumption is supported by the following reasons:
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> …projects with expiring contracts will have a competitive advantage to submit successful bids in upcoming solicitations conducted by SCE. These reasons include existing interconnection facilities, existing transmission pathways, paid-down capital, etc. Further, SCE has longstanding contractual relations with these parties, and therefore believes that it is favorably situated to extend these relationships under mutually agreeable terms.

Because of these inconsistent statements, it is unclear what the Report intends the above-referenced remark, found on page 49, to mean. SCE proposes that the Report be modified to state:

> A detailed review of the QF contracts throughout the study period indicated <u>probabilistic</u> changes to the level of production of some of the contracts which <u>ended during the study period. SCE assumed a 10 percent QF attrition rate, meaning that 90 percent of the capacity currently associated with contracts terminating during the planning period will remain under contract with SCE from the date of contract expiration at least through the end of the planning period.</u> ~~but did not reveal which contracts would not remain with SCE throughout the study period. There was no discussion by SCE of how it determined which contracts to change the production levels. However, SCE's alternate assumption of 90 percent QF contract extension is plausible, given the contingencies described.~~

Additionally, on page 49, the Report states:

> SCE's filing does not explain why the Alternative Case goes beyond just replacing the renewable QFs and adding more total renewables than in the Reference Case.

SCE responds that the Alternate Case has significantly more generic renewable resources than the Reference Case to account for a higher retail metered load resulting in a higher RPS GWh target. In addition, the Alternate Case has more generic renewables because of the higher attrition rate of QFs, as mentioned, in the Alternate Case and updated assumptions regarding Planned Renewable Contracts. To account for this explanation, the Report could be revised to state:

> SCE's filing ~~does not explain why the Alternative Case goes beyond just replacing the renewable QFs and adding more total renewables than in the Reference Case.~~ indicates that the Alternate Case has significantly more generic renewable resources than the Reference Case to account for a higher retail metered load resulting in a higher RPS GWh target. In addition, the alternate case has more generic renewables because of the higher attrition rate of QFs, as mentioned, in the Alternate Case, and updated assumptions regarding Planned Renewable Contracts.

Further, on page 49, the Report states,

> SCE provided little description or discussion of the models, spreadsheet tools or other analytic methods used in characterizing their renewable resource procurement and RPS compliance, other than replacing/procuring resources with least-cost best fit options available at the time or during the planning period.
>
> At this time, staff does not have access to modeling simulation results, spreadsheet detail, specific resource or cost data or assumptions used by SCE to arrive at the characterizations of renewable generation and costs for the various scenarios. It is difficult to respond to assertions, particularly regarding the Accelerated Renewable Scenario, in the absence of SCE's own detailed analysis that addresses or quantifies the set of issues or cost impacts SCE identifies.

The Report's complaints are misdirected. SCE was never asked for the very modeling simulation results, spreadsheet detail, specific resource or cost data or assumptions used by SCE to arrive at the characterizations of renewable generation and costs for the various scenarios. Accordingly, rather than fault SCE, the Report should acknowledge the failings of the IEPR. The Report should be revised to state:

> ~~At this time, staff does not have~~ CEC Staff did not request access to modeling simulation results, spreadsheet detail, specific resource or cost data or assumptions used by SCE to arrive at the characterizations of renewable generation

> and costs for the various scenarios. Therefore, it ~~It~~ is difficult to respond to assertions~~, particularly regarding the Accelerated Renewable Scenario, in the absence of SCE's own detailed analysis~~ that addresses or quantifies the set of issues or cost impacts SCE identifies. This is an area which deserves more research.

Another example of misstatements contained in the Report is found on page 49, where the Report states:

> SCE's March 7, 2005 filing with the CPUC contains more detailed information describing SCE's 10 year RPS Compliance Plan – key assumptions, compliance with existing RPS requirements, development of renewable resource portfolio and the ten-year plan, minimum transmission facilities needed to accommodate planned procurement activities, renewable resource repowering and expansions and lessons learned from SCE's 2003-2004 procurement efforts. This information is confidential and only available to RPS collaborative or PRG staff.

This statement fails to acknowledge that only a portion of SCE's RPS Procurement Plan was redacted. Additionally, key assumptions, compliance with existing RPS requirements, development of renewable resource portfolio and the ten-year plan, minimum transmission facilities needed to accommodate planned procurement activities, renewable resource repowering and expansions and lessons learned from SCE's 2003-2004 procurement efforts were described generally in the public version of the RPS Procurement Plan. To account for this, SCE offers the following revision to the Report:

> SCE's March 7, 2005 filing with the CPUC contains more detailed information describing SCE's 10 year RPS Compliance Plan – key assumptions, compliance with existing RPS requirements, development of renewable resource portfolio and the ten-year plan, minimum transmission facilities needed to accommodate planned procurement activities, renewable resource repowering and expansions and lessons learned from SCE's 2003-2004 procurement efforts. ~~This~~ Some specific information included in this report is confidential and only available to RPS collaborative or PRG staff. However, most of the report which includes general description of key

> assumptions, compliance with existing RPS requirements, development of renewable resource portfolio, renewable resource repowering and expansions and lessons learned from SCE's 2003-2004 procurement efforts is available publicly

Similarly, on page 50, the Report states,

> SCE states that the Accelerated Renewables Scenario appears to be the most expensive of the scenarios presented either on a present value of costs basis or an average scenario cost per megawatt-hour basis. SCE's narrative also reports that the accelerated renewables scenario exhibits lower marginal energy prices than the other cases because of an abundance of energy coming from must-take renewable resources that are tied to long-term contracts and do not impact system marginal costs. SCE offers an admittedly incomplete quantification and comparison of costs in each scenario. Data, assumptions and methods used to derive the scenario costs estimates were not provided. A more detailed assessment of the resource plan costs is presented in Chapter 7 of this report.

SCE believes that the information it provided sufficient data and components essential to be able to make a comparison between the provided scenarios. At no point was SCE requested to provide any additional information. Accordingly, the Report should be revised to state:

> SCE states that the Accelerated Renewables Scenario appears to be the most expensive of the scenarios presented either on a present value of costs basis or an average scenario cost per megawatt-hour basis. SCE's narrative also reports that the accelerated renewables scenario exhibits lower marginal energy prices than the other cases because of an abundance of energy coming from must-take renewable resources that are tied to long-term contracts and do not impact system marginal costs. SCE offers a ~~an admittedly incomplete~~ quantification and comparison of costs in each scenario. Data, assumptions and methods used to derive the scenario costs estimates were not ~~provided~~ requested. A more detailed assessment of the resource plan costs is presented in Chapter 7 of this report.

Chapter 5: Distributed Generation

Generally, this section of the Report claims that SCE provided very little information related to Distributed Generation ("DG"). As pointed out herein, such an accusation is baseless and should be removed from the Report. SCE provided exactly what the CEC requested in its instructions, and where such information was not available, SCE attempted to provide what information it had available.

For example, the Report states on page 65 that "No DG information is provided in their supply forecast forms." It further states that "regarding energy in SCE's DG forecast, no information is provided on energy produced from DG." These statements are not true. While it the supply forecast forms which SCE was instructed to fill out do not show specific DG values, to avoid double counting, SCE provided its DG forecast with the associated demand and energy forecast in its Demand Form 3.3 as required in its February 1, 2005, filing and updated February 7, 2005 ("Update Filing").

Further, on page 65, paragraph 2, the Report states that "it is unclear from SCE's submittal what criteria it uses to define DG versus QFs, independent power producers, bilateral contracted resources, etc." and "[n]o backup information is provided on assumptions used for hours of operation or performance of the different systems." The CEC must note that SCE completed Form 1.7 and Form 3.3 as provided. These forms neither requested that the energy or demand data be split into DG or QF categories, nor did they request information by fuel type or technology.

The Report further states, "no information on gas consumption information" was provided. SCE stated in its Update Filing that since it is an electric-only utility it does not have gas consumption information. Furthermore, SCE does not have information regarding the natural gas contracts customers using natural gas-fired DG have entered into and cannot predict how these customers choose to operate DG facilities, especially since SCE does not have actual production data on all DG.

Similarly, page 65 of the Report states, "SCE provides no cost information in Demand Form 3.3." As SCE pointed out in its Update Filing, Form 3.3 did not define which costs should be included in the response. The costs and benefits of distributed generation are currently being debated and determined in the Distributed Generation Rulemaking (R.04-03-017). SCE believes numerous costs should be considered, including but not limited to:

- Interconnection costs;
- Incentive Program costs;
- Costs of implicit subsidies and tariff exemptions on other ratepayers; and
- Costs associated with R&D and incorporation of DG into Distribution Planning.

Currently, the Self Generation Incentive Program costs approximately $32.5 million annually (through 2007) in the SCE service territory. The CEC administers the Emerging Renewables Program and reports that the program costs approximately $150 million statewide, funded by the PGC. Apart from incentive program costs, SCE does not currently have a method to quantify the costs listed above. SCE expects that further guidance on these issues will be provided in R.04-03-017.

Additionally, page 65 states, “it is not clear from the submitted information how SCE arrived at its yearly forecasts.” As SCE indicated in its Update Filing, SCE estimates generation impacts based on nameplate capacity and an estimate of the capacity factor for particular technology types. The historical numbers SCE provided in Form 3.3 are based on the installed capacity of all DG interconnections. The forecast numbers SCE provided are based on SCE’s estimate of future DG interconnections, taking into consideration factors affecting the rate of DG installations. Specifically, for the years 2005 through 2006, additions to new local generation are based on projects currently in the pipeline. The additional capacity is adjusted by the probability of installation. For the years 2007 through 2016, the forecast is based on the recent historical trend. SCE is willing to discuss the methodology used with the staff upon request.

Lastly, on page 66, the Staff compared SCE’s forecast with its own estimates. The Report states that “SCE’s future annual forecasts for commercial and industrial end use sectors could be low, or the agricultural end use sector forecasts for 2005-2016 could be high, or both.” SCE believes the CEC forecast for industrial local private supply may be high. There is an ongoing shift from manufacturing to non-manufacturing activity in the local economy. Based on this shift, the SCE forecast includes a slow but steady decline in industrial energy use. The CEC forecast shows a slow but steady increase in industrial energy use. The difference in industrial outlooks probably accounts for the difference in the industrial private supply between the two forecasts.

Chapter 7: Review of Resource Plan Potential Impacts And Uncertainties

The Report contains various statements regarding the potential impacts and uncertainties associated with SCE's resource plans. SCE addresses portions of the report dealing with cost estimates, core/non core scenarios, and transmission below.

Cost Estimates

On page 76, the Report states:

> Because some costs are excluded and so little detail is provided on the wide variety of line item cost components included, staff is unable to provide an independent assessment of the plausibility of SCE's cost estimates.

SCE's resource plan did include all significant and relevant transmission, generation, and demand-side program costs that would be expected to vary across cases were incorporated, as described in the narrative section of SCE's filing. Such information provides sufficient cost categories to allow the CEC to develop a fair comparison between the presented resource plan cases.

Additionally, on page 79 the Report states:

> Caution is warranted in interpreting these results. First, the percent changes reported in "total costs" are actually only changes in a smaller number—the portion of total costs that were actually tallied. The percent change of the actual "total cost" figure will necessarily be smaller than the percent change reported.

In interpreting the sensitivity of the resource plan costs to natural gas and market power prices, SCE agrees that caution should be observed when comparing the percentage change in costs. However, the magnitude of the change above or below the expected value is indicative of the magnitude of risk that the portfolio faces due to these uncertainties. The volatility of generation costs, including non-fixed QF payments, and market activity are both captured in the sensitivity analysis. Excluded costs, such as the costs of the DPV 2 transmission line and the steam generator replacement at SONGS, are unlikely to be impacted by the power, gas prices, or load fluctuations.

Core/Non-Core – Departing Load

At page 79, the Report states:

> SCE did not submit a "low load" resource plan. SCE assumes the current level of direct access persists in all resource cases.

SCE did not develop a "low load" resource plan because the CEC's instructions only asked IOUs to "evaluate a scenario under which IOU load falls as a result of future core/non-core policy decisions." While the CEC suggested a "low load" resource plan as a way of meeting the instructions, it did not require submission of such a plan. Accordingly, SCE followed the instructions when it developed its resource plan. In its Confidential Supplemental Tables, SCE provided the impact that the prescribed core/non-core scenario would have on its bundled customer peak load in comparison to the Reference Case.

<u>Comments on Greenhouse Gas Adder in Bid Evaluation</u>

At page 85, the Report states:

> It is not clear from SCE's description exactly how comparison of the proposed contract "relative to the assumed supply stack" would be accomplished.

The Report continues to describe that SCE's methodology could be consistent with that which the CEC has used in the past. Based on the description provided by the CEC, SCE would agree that the methods appear the same on the surface.

To perform the evaluation, a base supply stack that is sufficient to meet system demand and reserves would be dispatched against the load. Next, a proposed bid would be added to the supply stack and the resulting supply stack would be dispatched in the same system. The difference between the resulting emitted tons of greenhouse gases from the two stacks is valued at the avoided cost values for CO2 adopted in the Interim Opinion on E3 Avoided Cost Methodology (R.04-04-025). The calculated value is incorporated into the cash flow of the proposed bid, where a decrease in emissions is credited as a benefit and an increase is an extra cost. This process is performed for each bid individually.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.	))))	Rulemaking 04-04-026 (Filed April 22, 2004)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) OPENING BRIEF ON LEAST-COST AND BEST-FIT ISSUES

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.	))))	Rulemaking 04-04-026

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) OPENING BRIEF ON LEAST-COST AND BEST-FIT ISSUES

Southern California Edison Company (Edison) submits this Opening Brief on Least-Cost and Best-Fit Issues pursuant to the May 20, 2004 Administrative Law Judge's Ruling Establishing a Schedule for Consideration of Criteria for Rank Ordering and Selection of Least-Cost and Best-Fit Resources:

I.

INTRODUCTION

In order to implement the California Renewables Portfolio Standard (RPS) program, the Commission has been directed to adopt "[a] process that provides criteria for the rank ordering and selection of least-cost and best-fit renewable resources to comply with the annual California Renewables Portfolio Standard Program obligations on a total cost basis." Cal. Pub. Util. Code § 399.14(a)(2)(B). As the Commission recognized in D.03-06-071, "best fit is inextricably linked to the needs of a particular utility." D.03-06-071, *mimeo*, at p. 28 (Jun. 19, 2003). Accordingly, the Commission defined best fit "as being the renewable resources that best meet the utility's energy, capacity, ancillary service, and local reliability needs." *Id.*

The best fit process must "consider estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources." Cal. Pub. Util.

Code § 399.14(a)(2)(B). In D.03-06-071, the Commission directed that "remarketing costs [be] determined using the utility's own power dispatch models, which are under consideration in the general procurement proceeding." D.03-06-071, *mimeo*, at 34. However, as discussed below, Edison proposes to use its production simulation models broadly to capture the overall effects of individual renewable projects on total system production costs. This approach is in harmony with both the RPS statute and D.03-06-071 and will promote consistency between RPS implementation and general resource planning. *See* Cal. Pub. Util. Code § 399.14(a) ("To the extent feasible, [renewable] procurement plans shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process.").

II.

RFO SOLICITATION

A. Sequencing of RFOs

Commission rules governing RPS solicitations should be designed to maximize opportunities for cost-effective procurement from renewable resources and minimize opportunities for gaming. As discussed below, these objectives can best be accomplished by vesting in utilities the discretion to determine when to go to market.

Each utility should be free to gauge the most opportune timing to achieve the lowest-cost renewable portfolio benefits on behalf of its ratepayers. The Commission has already adopted flexible compliance rules backed up by potentially substantial penalties to ensure compliance with RPS procurement goals in each procurement year. Little would be gained by the Commission further managing the timing of solicitations under these circumstances.

Furthermore, a Commission rule providing that the timing of solicitations will be determined by the Commission, rather than procuring utilities, necessarily implies a level of market monitoring by the Commission that would likely impose an unwanted administrative burden on Commission staff and potentially result in controversy. While market prices for electricity are relatively stable today, recent history demonstrates the potential for extreme volatility in market prices. Even moderate fluctuations in natural gas prices could result in significant variances in market price referents (MPRs). Moreover, Edison's recent experience demonstrates that it is difficult to assess the length of time that will be necessary to complete a particular solicitation. Edison submits that utilities are in a better position to ascertain when the most optimal and cost-effective procurement can occur in any given procurement year, including whether to issue a solicitation while another utility's solicitation is pending.

Given that little will be gained by requiring any particular timing with respect to solicitations, Edison recommends that the Commission remain silent on this issue. As with other aspects of RPS implementation at this juncture, such as the MPR methodology, the Commission should adopt least-cost best-fit rules on an interim basis, allow some period of time for experience with the interim rules to develop and then revisit the rules to the extent they prove unworkable or do not meet statutory requirements or meet the Commission's policy objectives.

B. Bidding Requirements

Bidders may attempt to submit bids for the same project in more than one pending utility solicitation. This presents an obvious opportunity for gaming. If multiple bids are permitted, a single project developer could submit a high bid in one RFP and a lower bid in another, hoping that the higher bid will be accepted but expecting that the lower bid will be accepted. It is entirely possible in this scenario that the higher bid will be accepted for any number of reasons unrelated to the cost-effectiveness of project, such as the relative compliance positions of the procuring utilities (which will be known to bidders). Such a result does not further RPS goals of obtaining best-fit renewable resources at least-cost.

Moreover, a basic premise of the RFP process is that utilities should be able to reasonably rely on the bids that are received. Accordingly, utilities should have the discretion to require binding bids as part of their RFP protocol. If two utilities accept bids for the same project, a bidder will be forced to withdraw one of its bids. Utilities should be free to impose reasonable penalties, possibly including liquidated damages, on bidders who withdraw their bids.

C. Timing of Solicitation Review and AL Submittal

Based on Edison's experience, the time between the issuance of an RFO and the filing of advice letters seeking approval of RPS contracts is difficult to predict and can vary considerably. Further, it is likely that a utility will make multiple advice letter filings, as occurred previously with Edison's first interim solicitation and will likely occur again with Edison's pending solicitation. Actual timing will depend on a number of variables related to the complexity of the bids, requirements on the transmission systems, negotiations, PRG review and other factors, making it difficult to estimate with any degree of precision the length of time that will lapse between the issuance of an RFO and the filing of advice letters. This uncertainty further underscores the need to vest utilities with the discretion to determine when to go to market, as discussed above.

To a certain extent, resolution of various issues now pending before the Commission, *i.e.* standard terms and conditions, the MPR and least-cost/best-fit issues, is likely to facilitate utilities' and bidders' progress from the issuance of RFPs to the filing of advice letters. As a rule of thumb, Edison believes that it is reasonable to assume that it will take at least six months from the issuance of an RFO until completion of all negotiations and submission of advice letter filings with respect to successfully concluded negotiations.

III.

BID EVALUATION

A. Edison's Bid Analysis Process

Edison proposes to use production simulation models, in conjunction with a capacity proxy price, transmission costs and integration costs and benefits, to determine a benefit/cost ratio as basis for ranking bids on a least-cost and best-fit basis. The production simulation models are the same models used by Edison in the Resource Planning proceeding and also used in Edison's applications for other projects, such as the Mountainview project, the SONGS Steam Generator replacement filing and the Mohave Generating Station analysis. Using Edison's Resource Plan as a starting point establishes a consistent benchmark and methodology for the assessment of all future potential generation additions and treats new renewables the same as utility sponsored generating projects.

Edison proposes to use its latest resource plan and the Henwood Marketsym and Henwood Risksym production simulations models. The models consider the benefits and costs associated with a proposed renewable project. Specifically, the models calculate the replacement energy benefits associated with a particular project and subtract energy remarketing costs. The resource plan can be used to assure that any new renewable projects are the best fit with Edison's current and future generation portfolio to meet customer needs.

To complete the total benefit/cost analysis, Edison calculates replacement energy and capacity benefits using an adjusted combustion turbine (CT) proxy value[1] and subtracts applicable transmission costs, integration costs and debt equivalence costs. This analysis provides a relative constant measure of the effects of each renewable bid on system costs using bid-specific production profiles, thus accounting for the unique generation characteristics associated with each bid. The production simulation models are able to calculate the benefits and costs associated with a proposed project on an hour-by-hour basis. The debt equivalence component measures the relative risk to customers of differing contract lengths and appropriately captures the impact.

In order to compare proposed resources with different start dates, capacities, energy delivery patterns and contract durations, Edison calculates the net present value of the streams of costs and benefits over the life of a proposed project to determine a benefit/cost ratio. The projects are then ranked by their benefit/cost ratios. This effectively compares each project to a stream of benchmark benefits that is the same for all projects. Once the best projects are determined, Edison may add the projects in the order of their benefit/cost ratio to meet the RPS requirements.

Edison's proposed bid analysis process properly calculates the total system production cost benefits and costs associated with renewable projects in a manner that is consistent with the RPS statute and D.03-06-071. Moreover, the analysis process relies on models that are widely used in resource planning and are readily available.

B. Integration Costs and Capacity Issues

As Edison has stated previously in filings before the Commission and the California Energy Commission (CEC), Edison objects to the use of the CEC Phase 1 Integration Cost Analysis Study primarily because the study's conclusions are significantly at variance with Edison's experience, specifically with respect to the ELCC of wind resources and load following and regulation costs.

For the purpose of conducting the first round of RPS solicitations, the Commission should authorize use of both utility-specific data and, when possible, the results of the CEC study to evaluate the capacity values for all technologies. By

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1 Proposed projects are assigned a capacity value based on the Effective Load Carrying Capability (ELCC) associated with the resource type or, when applicable, based on other Commission

Continued on the next page

using both sets of data, the Commission will be able to determine whether the use of different assumptions concerning capacity values will change the bid rankings significantly. Additionally, zero costs for regulation and load-following should be used for the first round of RPS solicitations until additional studies or better comparisons of existing studies can be achieved.

Edison's proposed payment method is based on the traditional QF payment methodology, which has been used for many years. Edison believes that its proposed payment method is consistent with D.03-06-071. *See, e.g.,* D.03-06-071, Conclusion of Law 28, Ordering Paragraphs 11 and 12.

C. **Transmission Bid Adder**

The methodology for consideration of transmission costs in RPS procurement is currently under consideration in I.00-11-001. In that proceeding, Edison has proposed to calculate transmission bid adders using an annual revenue requirement covering both capital expenses and operation and maintenance costs. To date, adders have been calculated assuming full utilization of the transmission upgrade as of the date it is placed in service. However, this assumption may not be appropriate in all cases. Utilities should have the discretion to make adjustments to the transmission bid adder calculation when an assumption of full utilization is not appropriate.

D. **Qualitative Issues**

D.03-06-071 instructed renewable bidders to "describe potential benefits of their projects to the considerations of local reliability, low income or minority communities, environmental stewardship, and resource diversity." D.03-06-071, *mimeo*, at p. 37. The decision also directed the utilities to "apply transparent criteria in evaluating such claims, and [] present the results of these evaluations to their PRGs for consideration." *Id.*

Continued from the previous page
determined methodologies.

With the exception of local reliability and curtailability/dispatchability considerations, which are considered directly in Edison's bid analysis process, Edison recommends that qualitative benefits be considered as tie-breakers. The utilities should be permitted to exercise their discretion in evaluating these benefits, in consultation with their PRGs.

IV.

MPR AND SEP AWARDS

A. Definition of a "Peaking" Product

During the MPR workshops, Edison noted that current renewable technologies generally do not exhibit traditional "peaker" generation profiles. Typical peaking resources are fully dispatchable and deliver in approximately 10% of hours. However, solar projects, which are the only renewable facilities that approach a peaking product, typically deliver in approximately 30% of the hours. Failing to recognize the disparity between a true "peaking" product and the typical solar production profile will result in the inappropriate use of "peaking" MPR for a resource that is not truly a peaking product. Therefore, it would be appropriate to establish an MPR for "intermediate" facilities, to be applied to projects that generate mainly during peak hours.

B. SEP Award Issues

As the parties participating in the MPR and least-cost/best-fit workshops recognized, the 10-year statutory limitation on supplemental energy payments (SEPs) is potentially inconsistent with contract terms longer than 10 years. To harmonize a 10-year stream of SEPs with contact terms longer than 10 years, the CEC must be prepared to allocate sufficient funds over years 1-10 such that requisite SEPs can be made, if necessary, over years 11-15 or 11-20. Otherwise, there will be an abnormally inflated number of 10-year bids, to the detriment of ratepayers and the RPS program.

One legitimate way to achieve such an allocation is to place sufficient contract year 1 SEP funds into an escrow account[2] to pay the year 11 SEP requirement (accounting for how much interest the funds, placed in a risk-free account, would earn over 10 years), sufficient contract year 2 SEP funds into an escrow account to pay the year 12 SEP requirement, and so on. In any year, the additional SEP funds that would need to be allocated for future years could be established readily based on the 10-year treasury-bill interest rate. During years 11-15 or 11-20, SEP would be made to the project from the funds in the escrow account.

C. PRG Review Issues

Public Utilities Code section 399.14 provides that "[i]n order to ensure that the market price established by the commission . . . does not influence the amount of a bid submitted through the competitive solicitation . . . , and in order to ensure that the bid price does not influence the establishment of the market price, the electrical corporation shall not transmit or share the results of any competitive solicitation for eligible renewable energy resources until the commission has established market prices . . . ." Cal. Pub. Util. Code § 399.14(a)(2)(A). The statute, on its face, prohibits disclosure to the Commission and would, therefore, appear to require that Commission staff and collaborative staff not participate in PRG proceedings prior to such disclosures being made. Therefore, during utility

[2] The escrow account must be truly independent and devoted solely to the project receiving the award, *i.e.*, the funds must not be accessible by the CEC or other parties or governmental units.

solicitations, special meetings of the PRG, excluding Commission staff, should be convened to review bid results.

Respectfully submitted,

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<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) OPENING BRIEF ON LEAST-COST AND BEST-FIT ISSUES on all parties identified on the attached service list. Service was effected by means indicated below:

☒ Placing the copies in properly addressed sealed envelopes and depositing such envelopes in the United States mail with first-class postage prepaid (Via First Class Mail);

☐ Placing the copies in sealed envelopes and causing such envelopes to be delivered by hand to the offices of each addressee (Via Courier);

☒ Transmitting the copies via facsimile, modem, or other electronic means (Via Electronic Means).

Executed this 4th day of June **2004**, at Rosemead, California.

Andrea McAdoo

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